SOUTHWESTERN ENERGY CO
Form 10-Q
October 31, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities

Exchange Act of 1934

For the quarterly period ended September 30, 2013

Or

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities

Exchange Act of 1934

For the transition period from __________ to __________

Commission file number: 1-08246

Southwestern Energy Company
(Exact name of registrant as specified in its charter)

Delaware	71-0205415
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 North Sam Houston Parkway East, Suite 125, Houston, Texas	77032
(Address of principal executive offices)	(Zip Code)

(281) 618-4700

(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yesx   No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yesx No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer x   Accelerated filer o   Non-accelerated filer o   Smaller reporting company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o   No x
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding as of October 29, 2013
Common Stock, Par Value $0.01	351,752,517

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2013

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or si

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to fund our planned capital investments;
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;

- the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play overall as well as relative to other productive shale gas plays;
- the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over the counter derivatives;
- the costs and availability of oilfield personnel, services and drilling supplies, raw materials, and equipment, including pressure pumping equipment and crews;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale play and Marcellus Shale play;
- our future property acquisition or divestiture activities;
- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (“SEC”).

We caution you that forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in our Annual Report on Form 10-K for the year ended December 31, 2012 (the “2012 Annual Report on Form 10-K”), and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q (“Form 10-Qs”).

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-Q occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 617,427	$ 497,219	$ 1,736,101	$ 1,394,745
Gas marketing	201,112	148,764	581,932	423,503
Oil sales	4,397	1,889	12,431	6,097
Gas gathering	45,430	43,855	133,592	128,293
	868,366	691,727	2,464,056	1,952,638
Operating Costs and Expenses:				
Gas purchases – midstream services	195,271	149,651	575,337	423,941
Operating expenses	90,269	61,906	236,648	179,478
General and administrative expenses	50,969	36,121	135,754	129,879
Depreciation, depletion and amortization	204,934	203,935	571,268	605,392
Impairment of natural gas and oil properties	–	289,821	–	1,090,473
Taxes, other than income taxes	17,694	16,252	58,543	51,154
	559,137	757,686	1,577,550	2,480,317
Operating Income (Loss)	309,229	(65,959)	886,506	(527,679)
Interest Expense:				
Interest on debt	25,435	25,463	74,581	69,154
Other interest charges	1,049	1,058	3,203	3,096
Interest capitalized	(15,466)	(15,915)	(48,467)	(45,945)
	11,018	10,606	29,317	26,305
Other Gain (Loss), Net	(319)	238	(498)	2,615
Gain (Loss) on Derivatives	12,124	(5,879)	75,779	(10,593)
Income (Loss) Before Income Taxes	310,016	(82,206)	932,470	(561,962)
Provision for Income Taxes:				
Current	(16,068)	101	402	369
Deferred	140,217	(28,254)	373,055	(210,850)
	124,149	(28,153)	373,457	(210,481)
Net Income (Loss)	$ 185,867	$ (54,053)	$ 559,013	$ (351,481)

Earnings (Loss) Per Share:				
Basic	$ 0.53	$ (0.16)	$ 1.60	$ (1.01)
Diluted	$ 0.53	$ (0.16)	$ 1.59	$ (1.01)
Weighted Average Common Shares Outstanding:				
Basic	350,517,337	348,649,630	350,334,634	348,272,192
Diluted	351,222,830	348,649,630	351,014,974	348,272,192

See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Net income (loss)	$ 185,867	$ (54,053)	$ 559,013	$ (351,481)
Change in derivatives:				
Settlements [1]	(55,968)	(94,996)	(130,942)	(310,882)
Ineffectiveness [2]	872	322	1,310	(1,215)
Change in fair value of derivative instruments [3]	7,509	(36,468)	29,600	93,985
Total change in derivatives	(47,587)	(131,142)	(100,032)	(218,112)
Change in value of pension and other postretirement liabilities:				
Amortization of prior service cost included in net periodic pension cost [4]	266	254	800	762
Change in currency translation adjustment	633	997	(1,814)	962
Comprehensive income (loss)	$ 139,179	$ (183,944)	$ 457,967	$ (567,869)

(1) Net of ($37.3), ($62.2), ($87.3) and ($202.6) million in taxes for the three months ended September 30, 2013 and 2012, and nine months ended September 30, 2013 and 2012, respectively.

(2) Net of $0.6, $0.2, $0.9 and ($0.8) million in taxes for the three months ended September 30, 2013 and 2012, and nine months ended September 30, 2013 and 2012, respectively.

(3) Net of $5.0, ($22.1), $19.7, and $62.7 million in taxes for the three months ended September 30, 2013 and 2012, and nine months ended September 30, 2013 and 2012, respectively.

(4) Net of \$0.2, \$0.2, \$0.5, and \$0.5 million in taxes for the three months ended September 30, 2013 and 2012, and nine months ended September 30, 2013 and 2012, respectively.

See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
ASSETS	(in thousands)	
Current assets:		
Cash and cash equivalents	$ 18,950	$ 53,583
Restricted cash	–	8,542
Accounts receivable	444,723	377,638
Inventories	43,225	28,141
Hedging asset	197,647	282,693
Other current assets	35,430	58,315
Total current assets	739,975	808,912
Natural gas and oil properties, using the full cost method, including $1,101.5 million in 2013 and $1,023.9 million in 2012 excluded from amortization	12,863,859	11,283,114
Gathering systems	1,282,652	1,148,261
Other	677,042	597,064
Less: Accumulated depreciation, depletion and amortization	(7,786,820)	(7,191,463)
Total property and equipment, net	7,036,733	5,836,976
Other long-term assets	117,680	91,639
TOTAL ASSETS	$ 7,894,388	$ 6,737,527
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 601,414	$ 459,569
Taxes payable	48,263	62,980
Interest payable	14,049	34,431
Advances from partners	3,438	68,919
Current deferred income taxes	75,954	106,123
Other current liabilities	66,693	35,749
Total current liabilities	809,811	767,771
Long-term debt	1,911,165	1,668,273
Deferred income taxes	1,388,833	1,049,138
Pension and other postretirement liabilities	34,963	33,174
Other long-term liabilities	229,627	183,299
Total long-term liabilities	3,564,588	2,933,884
Commitments and contingencies (Note 11)		
Equity:		
Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 351,768,352	3,517	3,511

shares in 2013 and 351,100,391 in 2012		
Additional paid-in capital	960,058	934,939
Retained earnings	2,508,163	1,949,150
Accumulated other comprehensive income	48,758	149,804
Common stock in treasury, 14,625 shares in 2013 and 64,715 in 2012	(507)	(1,532)
Total equity	3,519,989	3,035,872
TOTAL LIABILITIES AND EQUITY	$ 7,894,388	$ 6,737,527

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the nine months ended September 30, 2013	2012
	(in thousands)	
Cash Flows From Operating Activities		
Net income (loss)	$ 559,013	$ (351,481)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	574,221	608,167
Impairment of natural gas and oil properties	–	1,090,473
Deferred income taxes	373,055	(210,850)
Mark to market gain on derivatives	(72,664)	(892)
Stock-based compensation	8,883	8,226
Other	3,038	(1,686)
Change in assets and liabilities:		
Accounts receivable	(67,070)	44,148
Inventories	(13,449)	16,608
Accounts payable	45,189	(11,050)
Taxes payable	(14,717)	(3,789)
Interest payable	(7,682)	(2,306)
Advances from partners	(65,481)	26,155
Other assets and liabilities	55,182	(19,246)
Net cash provided by operating activities	1,377,518	1,192,477
Cash Flows From Investing Activities		
Capital investments	(1,727,543)	(1,623,751)
Proceeds from sale of property and equipment	3,081	201,161
Transfers to restricted cash	–	(167,774)
Transfers from restricted cash	8,542	40,700
Other	4,700	5,239
Net cash used in investing activities	(1,711,220)	(1,544,425)
Cash Flows From Financing Activities		
Payments on current portion of long-term debt	(600)	(600)
Payments on revolving long-term debt	(2,134,550)	(1,774,000)
Borrowings under revolving long-term debt	2,377,950	1,129,000
Change in bank drafts outstanding	49,106	1,627

Proceeds from issuance of long-term debt	–	998,780
Debt issuance costs	–	(8,338)
Proceeds from exercise of common stock options	6,751	8,422
Net cash provided by financing activities	298,657	354,891
Effect of exchange rate changes on cash	412	(10)
Increase (decrease) in cash and cash equivalents	(34,633)	2,933
Cash and cash equivalents at beginning of year	53,583	15,627
Cash and cash equivalents at end of period	$ 18,950	$ 18,560

See the accompanying notes which are an integral part of

these unaudited condensed consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Common Stock Shares Issued	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
	(in thousands)						
Balance at December 31, 2012	351,100	$ 3,511	$ 934,939	$ 1,949,150	$ 149,804	$ (1,532)	$ 3,035,872
Comprehensive income (loss):							
Net income	–	–	–	559,013	–	–	559,013
Other comprehensive loss	–	–	–	–	(101,046)	–	(101,046)
Total comprehensive income	–	–	–	–	–	–	457,967
Stock-based compensation	–	–	17,426	–	–	–	17,426
Exercise of stock options	706	7	6,768	–	–	–	6,775
Issuance of restricted stock	21	–	–	–	–	–	–
Cancellation of restricted stock	(59)	(1)	1	–	–	–	–
Treasury stock – non-qualified plan	–	–	924	–	–	1,025	1,949
Balance at September 30, 2013	351,768	$ 3,517	$ 960,058	$ 2,508,163	$ 48,758	$ (507)	$ 3,519,989

See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION

Southwestern Energy Company (including its subsidiaries, collectively, “we”, “Southwestern” or the “Company”) is an independent energy company engaged in natural gas and oil exploration, development and production. The Company engages in natural gas and oil exploration and production, natural gas gathering and natural gas marketing through its subsidiaries. Southwestern’s exploration, development and production (“E&P”) activities are focused within the United States.   The Company is actively engaged in exploration and production activities in Arkansas, where we are targeting the unconventional gas reservoir known as the Fayetteville Shale, in Pennsylvania, where we are targeting the unconventional gas reservoir known as the Marcellus Shale, and to a lesser extent in Texas and in Arkansas and Oklahoma in the Arkoma Basin. The Company also actively seeks to find and develop new oil and natural gas plays with significant exploration and exploitation potential. Southwestern’s natural gas gathering and marketing (“Midstream Services”) activities primarily support the Company’s E&P activities in Arkansas, Pennsylvania and Texas.

The accompanying unaudited condensed consolidated financial statements were prepared using accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information and in accordance with the rules and regulations of the Securities and Exchange Commission. Certain information relating to the Company’s organization and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been appropriately condensed or omitted in this Quarterly Report on Form 10-Q. The Company believes the disclosures made are adequate to make the information presented not misleading.

The unaudited condensed consolidated financial statements contained in this report include all normal and recurring material adjustments that, in the opinion of management, are necessary for a fair statement of the financial position, results of operations and cash flows for the interim periods presented herein. It is recommended that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and the notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2012 (“2012 Annual Report on Form 10-K”).

The Company’s significant accounting policies, which have been reviewed and approved by the Audit Committee of the Company’s Board of Directors, are summarized in Note 1 in the Notes to the Consolidated Financial Statements included in the Company’s 2012 Annual Report on Form 10-K.

Certain reclassifications have been made to the prior year financial statements to conform to the 2013 presentation. The effects of the reclassifications were not material to the Company's unaudited condensed consolidated financial statements.

(2) ACQUISITIONS AND DIVESTITURES

In April 2013, the Company entered into a definitive purchase agreement to acquire natural gas properties located in Pennsylvania prospective for the Marcellus Shale for approximately $93.0 million, subject to closing conditions. The Company utilized its revolving credit facility to finance the acquisition. The Company closed on the acquisition during the second quarter of 2013 and accounted for it as an asset acquisition.

In May 2012, the Company sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $166.0 million. The assets included in the sale represented all of the Company's interests and related assets in the Overton Field in Smith County. The net production from the sold assets was approximately 24.0 MMcfe per day as of the closing date and the associated net proved reserves were approximately 143.0 Bcfe at December 31, 2011.

(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of September 30, 2013 and December 31, 2012 consisted of the following:

	September 30, 2013	December 31, 2012
	(in thousands)	
Prepaid drilling costs	$ 15,622	$ 30,101
Prepaid insurance	9,536	9,507
Total	$ 25,158	$ 39,608

(4) INVENTORY

Inventory recorded in current assets includes $3.7 million at September 30, 2013 and $5.6 million at December 31, 2012 for natural gas in underground storage owned by the Company’s E&P segment, and $39.5 million at September 30, 2013 and $22.5 million at December 31, 2012 for tubular and other equipment used in the E&P segment.

Other long-term assets include $15.8 million at September 30, 2013 and $13.8 million at December 31, 2012, respectively, for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale play.

(5) NATURAL GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country by country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves, net of taxes, discounted at 10 percent plus the lower of cost or market value of unproved properties.

Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.60 per MMBtu and $91.56 per barrel for West Texas Intermediate oil, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at September 30, 2013. Cash flow hedges of natural gas production in place increased the ceiling value by $79.2 million, net of tax, at September 30, 2013. Decreases in average quoted prices from September 30, 2013 levels as well as changes in production rates, levels of reserves, capitalized costs, the evaluation of costs excluded from amortization, future development costs, service costs and taxes could result in future ceiling test impairments.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.83 per MMBtu and $91.48 per barrel for West Texas Intermediate oil, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $185.7 million (net of tax) at September 30, 2012 and resulted in a non-cash ceiling test impairment. Cash flow hedges of natural gas production in place increased the ceiling by $330.6 million at September 30, 2012. In the second quarter of 2012, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $496.4 million (net of tax) at June 30, 2012 and resulted in a non-cash ceiling test impairment.

All of the Company's costs directly associated with the acquisition and evaluation of properties in Canada relating to its exploration program at September 30, 2013 were unproved and did not exceed the ceiling amount. If the exploration program in Canada is unsuccessful on all or a portion of these properties, a ceiling test impairment may result in the future.

(6) EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three- and nine-month periods ended September 30, 2013 and 2012:

	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
Net income (loss) (in thousands)	$ 185,867	$ (54,053)	$ 559,013	$ (351,481)
Number of common shares:				
Weighted average outstanding	350,517,337	348,649,630	350,334,634	348,272,192
Issued upon assumed exercise of outstanding stock options	373,152	–	442,678	–
Effect of issuance of nonvested restricted common stock	332,341	–	237,662	–
Weighted average and potential dilutive outstanding[1]	351,222,830	348,649,630	351,014,974	348,272,192
Earnings (loss) per share:				
Basic	$ 0.53	$ (0.16)	$ 1.60	$ (1.01)
Diluted	$ 0.53	$ (0.16)	$ 1.59	$ (1.01)

(1) Options for 1,550,838 shares and 15,703 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2013 because they would have had an antidilutive effect. Due to the net loss for the three months ended September 30, 2012, options for 1,664,232 shares and 560,848 shares of restricted stock were antidilutive and excluded from the calculation. Options for 1,848,566 shares and 169,261 shares of restricted stock were excluded from the calculation for the nine months ended September 30, 2013 because they would have had an

antidilutive effect. Due to the net loss for the nine months ended September 30, 2012, options for 1,685,398 shares and 580,227 shares of restricted stock were antidilutive and excluded from the calculation.

(7) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas and crude oil which impacts the predictability of its cash flows related to the sale of natural gas and oil, and is exposed to volatility in interest rates. These risks are managed by the Company's use of certain derivative financial instruments. At September 30, 2013 and December 31, 2012, the Company's derivative financial instruments consisted of fixed price swaps, basis swaps, fixed price call options, and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
Floating price swaps	The Company receives a floating market price from the counterparty and pays a fixed price.
Costless-collars	Arrangements that contain a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.
Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
Fixed price call options	The Company sells fixed price call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty such excess on sold fixed price call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
Interest rate swaps	Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest-rate changes.

GAAP requires that all derivatives be recognized in the balance sheet as either an asset or liability and be measured at fair value. Under GAAP, certain criteria must be satisfied in order for derivative financial instruments to be classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative's gains and losses to be recorded either in earnings as a component of the sale of natural gas and oil or as a component of other comprehensive income. Gains and losses on derivatives that are not elected for hedge accounting treatment or that do not meet hedge accounting requirements are recorded in earnings as a component of gain (loss) on derivatives. Within the gain (loss) on derivatives component of the statement of operations are mark to market gain (loss) on derivatives and mark to market gain (loss) on derivatives, settled. The Company calculates mark to market gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period reported.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy at the time the transactions are entered into and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The balance sheet classification of the assets related to derivative financial instruments are summarized below at September 30, 2013 and December 31, 2012:

	Derivative Assets September 30, 2013 Balance Sheet Classification	Fair Value	December 31, 2012 Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed price swaps	Hedging asset	$ 115,039	Hedging asset	$ 279,443
Fixed price swaps	Other long-term assets	5,951	Other long-term assets	8,550
Total derivatives designated as hedging instruments		$ 120,990		$ 287,993
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging asset	$ 5,104	Hedging asset	$ 3,250
Fixed price swaps	Hedging asset	77,504	Hedging asset	–
Basis swaps	Other long-term assets	679	Other long-term assets	901
Fixed price swaps	Other long-term assets	19,103	Other long-term assets	–
Interest rate swaps	Other long-term assets	5,797	Other long-term assets	–
Total derivatives not designated as hedging instruments		$ 108,187		$ 4,151
Total derivative assets		$ 229,177		$ 292,144

	Derivative Liabilities September 30, 2013 Balance Sheet Classification	Fair Value	December 31, 2012 Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives not designated as hedging instruments:				
Basis swaps	Other current liabilities	$ 164	Other current liabilities	$ 138
Fixed price call options	Other long-term liabilities	30,980	Other long-term liabilities	4,128
Interest rate swaps	Other current liabilities	912	Other current liabilities	–
Interest rate swaps	Other long-term liabilities	3,582	Other long-term liabilities	–

Total derivatives not designated as hedging instruments	$ 35,638	$ 4,266
Total derivative liabilities	$ 35,638	$ 4,266

As of September 30, 2013, the Company had derivatives designated as cash flow hedges and derivatives not designated as hedges on the following volumes of natural gas production (in Bcf):

Year	Fixed price swaps	Fixed price swaps not designated for hedge accounting	Total
2013	84.4	-	84.4
2014	51.1	181.6	232.7

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Cash Flow Hedges

The reporting of gains and losses on cash flow derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gains and losses on the derivative hedging instruments are recorded in other comprehensive income until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from the derivative hedging instrument is recognized in earnings immediately.

As of September 30, 2013, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $72.1 million. This amount is net of a deferred income tax liability recorded as of September 30, 2013 of $48.1 million. The amount recorded in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Assuming the market prices of natural gas futures as of September 30, 2013 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of $68.6 million from accumulated other comprehensive income to earnings during the next 12 months. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to gas sales in the unaudited condensed consolidated statements of operations. Volatility in earnings and other comprehensive income may occur in the future as a result of the Company’s derivative activities.

The following tables summarize the before tax effect of all cash flow hedges on the unaudited condensed consolidated financial statements for the three- and nine-month periods ended September 30, 2013 and 2012:

	Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion)			
	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	2013	2012	2013	2012
	(in thousands)			
Fixed price swaps	$ 12,515	$ (55,039)	$ 51,234	$ 116,089
Costless-collars	$ –	$ (3,497)	$ –	$ 40,644

Derivative Instrument	Classification of Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
		2013	2012	2013	2012
		(in thousands)			
Fixed price swaps	Gas sales	$ 93,280	$ 102,789	$ 218,236	$ 337,994
Costless-collars	Gas sales	$ –	$ 54,489	$ –	$ 175,531

Derivative Instrument	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
		2013	2012	2013	2012
		(in thousands)			
Fixed price swaps	Gas sales	$ (1,452)	$ (165)	$ (2,183)	$ 1,831
Costless-collars	Gas sales	$ –	$ (373)	$ –	$ 167

Fair Value Hedges and Other Derivative Contracts

For fair value hedges, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately.

Although the Company's basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company's derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. Basis swap derivative instruments that do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under hedging assets, other long-term assets and other current liabilities, as applicable, and all gains and losses related to these contracts are recognized immediately in the unaudited condensed consolidated statements of operations as a component of gain (loss) on derivatives.

As of September 30, 2013, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 6.5 Bcf, 16.7 Bcf, and 0.9 Bcf in 2013, 2014, and 2015, respectively.

As of September 30, 2013, the Company had fixed price call options on 199.8 Bcf of 2015 natural gas production that did not qualify for hedge accounting treatment and fixed price swaps of 181.6 Bcf of 2014 natural gas production not designated for hedge accounting.

The Company is a party to an interest rate swap with counterparty banks. The interest rate swap was entered into in order to mitigate the Company's exposure to volatility in interest rates related to its building lease. The interest rate swap has a notional amount of $170.0 million and expires on June 20, 2020. The Company did not designate the interest rate swap for hedge accounting. Changes in the fair value of the interest rate swap are included in gain (loss) on derivatives in the unaudited condensed consolidated statements of operations. The Company had no interest rate swaps in 2012.

The following table summarizes the before tax effect of fair value hedges, fixed price call options that did not qualify for hedge accounting, fixed price swaps not designated for hedge accounting, basis swaps, and interest rate swaps not designated for hedge accounting on the unaudited condensed consolidated statements of operations for the three- and nine-month periods ended September 30, 2013 and 2012:

Mark to Market Gain (Loss)

Derivative Instrument	Income Statement Classification of Mark to Market Gain (Loss) on Derivatives	on Derivatives Recognized in Earnings For the three months ended September 30, 2013	2012	For the nine months ended September 30, 2013	2012
		(in thousands)			
Basis swaps	Gain (Loss) on Derivatives	$ (5,279)	$ (1,275)	$ 1,606	$ (270)
Fixed price call options	Gain (Loss) on Derivatives	$ 7,876	$ –	$ (26,852)	$ –
Fixed price swaps	Gain (Loss) on Derivatives	$ 8,819	$ –	$ 96,606	$ –
Interest rate swaps	Gain (Loss) on Derivatives	$ (1,312)	$ –	$ 1,304	$ –
Fair value swaps	Gain (Loss) on Derivatives	$ –	$ 136	$ –	$ 1,162

Derivative Instrument	Income Statement Classification of Mark to Market Gain (Loss) on Derivatives, Settled [1]	Mark to Market Gain (Loss) on Derivatives, Settled [1] Recognized in Earnings For the three months ended September 30, 2013	2012	For the nine months ended September 30, 2013	2012
		(in thousands)			
Basis swaps	Gain (Loss) on Derivatives	$ 2,020	$ 624	$ 3,115	$ 1,773
Fair value swaps	Gain (Loss) on Derivatives	$ –	$ (5,364)	$ –	$ (13,258)

(1) The Company calculates mark to market gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period reported.

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(8) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

The following tables detail the components of accumulated other comprehensive income and the related tax effects for the nine-months ended September 30, 2013:

	For the nine months ended September 30, 2013			
	Gains and Losses on Cash Flow Hedges	Pension and Other Postretirement	Foreign Currency	Total
	(in thousands) [1]			
Beginning balance, December 31, 2012	$ 172,166	$ (22,311)	$ (51)	$ 149,804
Other comprehensive income (loss) before reclassifications	29,600	–	(1,814)	27,786
Amounts reclassified from accumulated other comprehensive income (loss) [2]	(129,632)	800	–	(128,832)
Net current-period other comprehensive income (loss)	(100,032)	800	(1,814)	(101,046)
Ending balance, September 30, 2013	$ 72,134	$ (21,511)	$ (1,865)	$ 48,758

(1) All amounts are net-of-tax.
(2) See separate table below for details about these reclassifications.

The following table details the amounts reclassified from accumulated other comprehensive income into earnings for the nine-months ended September 30, 2013:

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income For the nine months ended September 30, 2013 (in thousands)
Gains (losses) on cash flow hedges		
Settlements	Gas sales	$ 218,236
Ineffectiveness	Gas sales	(2,183)
	Income before income taxes	216,053
	Provision for income taxes	86,421
	Net income	$ 129,632
Pension and other postretirement		
Amortization of prior service cost included in net periodic pension cost [1]	General and administrative expenses	$ (1,334)
	Loss before income taxes	(1,334)
	Benefit for income taxes	(534)
	Net loss	$ (800)
Total reclassifications for the period	Net income	$ 128,832

(1) Included in the computation of net periodic pension cost (see footnote 13 for additional details.)

(9) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of September 30, 2013 and December 31, 2012 were as follows:

	September 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	$ 18,950	$ 18,950	$ 53,583	$ 53,583
Restricted cash	$ –	$ –	$ 8,542	$ 8,542
Unsecured revolving credit facility	$ 243,400	$ 243,400	$ –	$ –
Senior notes	$ 1,668,965	$ 1,807,234	$ 1,669,473	$ 1,917,005
Derivative instruments	$ 193,539	$ 193,539	$ 287,878	$ 287,878

The carrying values of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, other current assets and current liabilities on the unaudited condensed consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's senior notes were based on the market for the Company's publicly-traded debt as determined based on yield of the Company's 7.5% Senior Notes due 2018, which was 2.8% at September 30, 2013 and 2.6% at December 31, 2012, and its 4.10% Senior Notes due 2022, which was 4.0% at September 30, 2013. The carrying value of the borrowings under the Company's unsecured revolving credit facility at September 30, 2013, approximate fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

Derivative Instruments: The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations - Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

Level 2 valuations - Consist of quoted market information for the calculation of fair market value.

Level 3 valuations - Consist of internal estimates and have the lowest priority.

Pursuant to GAAP, the Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company’s Level 2 fair value measurements include fixed-price swaps and are estimated using internal discounted cash flow calculations using the NYMEX futures index. The Company utilizes discounted cash flow models for valuing its interest rate derivatives. The net derivative values attributable to the Company's interest rate derivative contracts as of September 30, 2013 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's interest rate derivative asset and liability measurements represent Level 2 inputs in the hierarchy. The Company’s Level 3 fair value measurements include fixed price call options and basis swaps. The Company’s fixed price call options are valued using the Black-Scholes model, an industry standard option valuation model, and takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company’s basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves.

The accounting group, reporting to the Vice President and Controller, is responsible for determining the Company’s Level 3 fair value measurements. Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in thousands):

	September 30, 2013 Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$ –	$ 223,394	$ 5,783	$ 229,177
Derivative liabilities	–	(4,494)	(31,144)	(35,638)
Total	$ –	$ 218,900	$ (25,361)	$ 193,539

	December 31, 2012 Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$ –	$ 287,993	$ 4,151	$ 292,144
Derivative liabilities	–	–	(4,266)	(4,266)
Total	$ –	$ 287,993	$ (115)	$ 287,878

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three- and nine-month periods ended September 30, 2013 and September 30, 2012. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company’s judgment, reflect the assumptions a reasonable marketplace participant would have used at September 30, 2013 and September 30, 2012.

	For the three months ended September 30, 2013	For the three months ended September 30, 2012	For the nine months ended September 30, 2013	For the nine months ended September 30, 2012
	(in thousands)			
Balance at beginning of period	$ (27,958)	$ 106,222	$ (115)	$ 182,119
Total gains (losses):				
Included in earnings	4,617	53,465	(22,131)	177,201
Included in other comprehensive income	–	(57,614)	–	(135,055)
Purchases, issuances, and settlements:				
Purchases	–	–	–	–
Issuances	–	–	–	–
Settlements	(2,020)	(55,112)	(3,115)	(177,304)
Transfers into/out of Level 3	–	–	–	–
Balance at end of period	$ (25,361)	$ 46,961	$ (25,361)	$ 46,961
Change in gains (losses) included in earnings relating to derivatives still held as of September 30	$ 2,597	$ (1,647)	$ (25,246)	$ (103)

(10) DEBT

The components of debt as of September 30, 2013 and December 31, 2012 consisted of the following:

	September 30, 2013	December 31, 2012
	(in thousands)	
Short-term debt:		
7.15% Senior Notes due 2018	$ 1,200	$ 1,200
Total short-term debt	1,200	1,200
Long-term debt:		
Variable rate (2.14% at September 30, 2013) unsecured revolving credit facility	243,400	–
7.5% Senior Notes due 2018	600,000	600,000
7.35% Senior Notes due 2017	15,000	15,000
7.125% Senior Notes due 2017	25,000	25,000
7.15% Senior Notes due 2018	28,800	29,400
4.10% Senior Notes due 2022	1,000,000	1,000,000
Unamortized discount	(1,035)	(1,127)
Total long-term debt	1,911,165	1,668,273
Total debt	$ 1,912,365	$ 1,669,473

Issuance of Senior Notes and Subsidiary Guarantees

The indentures governing the Company's senior notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries' ability to incur liens, to engage in sale and leaseback transactions and to merge, consolidate, or sell assets. All of the Company's senior notes are currently guaranteed by its subsidiaries, SEECO, Inc. ("SEECO"), Southwestern Energy Production Company ("SEPCO") and Southwestern Energy Services Company ("SES"). If no default or event of default has occurred and is continuing, these guarantees will be released (i) automatically upon any sale, exchange, or transfer of all of the Company's equity interests in the guarantor; (ii) automatically upon the liquidation and dissolution of a guarantor; (iii) following delivery of notice to the trustee of the release of the guarantor of its obligations under the Company's credit facility; and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the notes.

In December 2012, the Company completed its offer to exchange up to $1.0 billion aggregate principal amount of its 4.10% Senior Notes due 2022 (the "Exchange Notes", which were registered under the Securities Act of 1933, as amended (the "Act"), for any and all of its outstanding 4.10% Senior Notes due 2022, which were issued in a private placement in March 2012 (the "Private Notes"). The Exchange Notes have substantially identical terms to the Private Notes, except that the offering of the Exchange Notes was registered under the Act, and the Exchange Notes are not subject to any transfer restrictions. The Company exchanged $999,500,000 of Private Notes for Exchange Notes, and has no further obligations under the related registration rights agreement.

Please refer to Note 17, "Condensed Consolidating Financial Information" in this Form 10-Q for additional information.

Credit Facility

In February 2011, the Company amended and restated its unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016 ("Credit Facility"). The amount available under the Credit Facility may be increased to $2.0 billion at any time upon the Company's agreement with its existing or additional lenders. The interest rate on the Credit Facility is calculated based upon our debt rating and is currently 200 basis points over the current London Interbank Offered Rate (LIBOR) and was 200 basis points over LIBOR at September 30, 2013. The Credit Facility is guaranteed by the Company's subsidiary, SEECO and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. The terms of the Credit Facility also include covenants that restrict the ability of the Company and its material subsidiaries to merge, consolidate or sell all or substantially all of their assets, restrict the ability of the Company and its subsidiaries to incur liens and restrict the ability of the Company's subsidiaries to incur indebtedness. As of September 30, 2013, the Company was in compliance with the covenants of its debt agreements. While the Company believes all of the lenders under the Credit Facility have the ability to provide funds, it cannot predict whether each will be able to meet its obligation under the facility.

(11) COMMITMENTS AND CONTINGENCIES

Commitments

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately $47.0 million in the aggregate over a three year period. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $44.5 million Canadian dollars. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of September 30, 2013 has invested $35.4 million in New Brunswick towards the Company's commitment. In December 2012, the Company received two one-year extensions to our exploration license agreements which expire on March 16, 2014 and March 16, 2015, respectively. No liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of September 30, 2013 and its future investment plans.

In response to the Company's well performance, SES and SEPCO entered into new and amended natural gas transportation and gathering arrangements with third party pipelines, during the second quarter of 2013, in support of the Company's production in the Marcellus Shale Play. As of September 30, 2013, the Company's obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $3.4 billion and the Company has guarantee obligations of up to $100.0 million of that amount.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

Litigation

Tovah Energy

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273rd District Court in Shelby County, Texas (collectively, the "Sixth Petition"), plaintiff alleged that, in 2005, they provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiff's allegations in the Sixth Petition included various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 2005 and February 2006. In the Sixth Petition, plaintiff sought actual damages of over $55.0 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of $46.0 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. In December 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. In February 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. In March 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred in April 2011 and was unsuccessful. In June 2011, SEPCO received by mail a letter dated June 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. In July 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response in July 2011. In July 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 2011 consistent with his findings in his June 2011 letter and the disgorgement award. In August 2011, a judgment was entered pursuant to which plaintiff and intervenor are entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees which currently are estimated to be up to $8.9 million and all costs of court of the plaintiff and intervenor. In September 2011, SEPCO filed a motion for a new trial and in November 2011 filed a notice of appeal. In November 2011, the court approved SEPCO's supersedeas bond in the amount of $14.1 million, which stays execution on the judgment pending appeal. The bond covers the $11.4 million judgment for actual damages, plus $1.3 million in pre-judgment interest, $1.3 million in post-judgment interest (estimating two years for the duration of appeal), and court costs.

In June 2012, SEPCO filed its appellate brief and, in June 2012, plaintiff and intervenor filed a cross-appellate brief seeking limited remand to reassess the disgorgement determination. The parties filed their responses to the appellate and cross appellate briefs in November 2012. Oral argument was held before the Tyler Court of Appeals on March 8, 2013. On July 10, 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding plaintiff and intervenor $23.9 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11.4 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that plaintiff and intervenor take nothing under those theories of recovery, (3) the award of $11.4 million to plaintiff and intervenor as damages for misappropriation of trade secret is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for SEPCO as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. On July 25, 2013, SEPCO filed its motion for rehearing with the Tyler Court of Appeals, seeking reversal of every part of plaintiff and intervenor's recovery, and plaintiff and intervenor filed a court-ordered response. Plaintiff and intervenor filed their own motion for rehearing, and to date SEPCO has not been ordered to respond.

Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $45.5 million, including interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

Bureau of Land Management

In March 2010, the Company's subsidiary, SEECO, was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefore and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. In September 2013, the U.S. Attorney's Office requested additional information regarding this matter. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

Other

We are subject to various litigation, claims and proceedings that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

(12) SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

Supplemental disclosures of cash flow information:

	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Cash paid for interest	$ 44,745	$ 45,667	$ 94,963	$ 75,487
Cash paid for income taxes	$ 1,330	$ 400	$ 18,636	$ 468
Noncash property changes	$ (11,745)	$ (55,729)	$ 34,437	$ (34,940)

(13) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has defined pension and postretirement benefit plans which cover substantially all of the Company's employees. Net periodic pension and other postretirement benefit costs include the following components for the three-and nine-month periods ended September 30, 2013 and 2012:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Service cost	$ 3,447	$ 2,736	$ 10,342	$ 8,207
Interest cost	1,026	1,013	3,078	3,038
Expected return on plan assets	(1,534)	(1,356)	(4,602)	(4,069)
Amortization of prior service cost	25	71	77	214
Amortization of net loss	386	305	1,156	915
Net periodic benefit cost	$ 3,350	$ 2,769	$ 10,051	$ 8,305

	Postretirement Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Service cost	$ 574	$ 458	$ 1,722	$ 1,374
Interest cost	111	100	331	299
Amortization of transition obligation	–	16	–	48
Amortization of prior service cost	4	4	11	11
Amortization of net loss	30	23	90	69
Net periodic benefit cost	$ 719	$ 601	$ 2,154	$ 1,801

As of September 30, 2013, the Company has contributed $9.0 million to the pension plan and $0.1 million to the postretirement benefit plan, and expects to contribute an additional $3.0 million to the pension plan in 2013.

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan ("Non-Qualified Plan") for certain key employees who may elect to defer and contribute a portion of their compensation, as permitted by the plan. Shares of the Company's common stock purchased under the terms of the Non-Qualified Plan are presented as treasury stock and totaled 14,625 shares at September 30, 2013 compared to 64,715 shares at December 31, 2012.

(14) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three- and nine-months ended September 30, 2013 and 2012:

	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Stock-based compensation cost – expensed	$ 2,921	$ 2,677	$ 8,883	$ 8,226
Stock-based compensation cost – capitalized	$ 2,809	$ 2,482	$ 8,543	$ 7,788

As of September 30, 2013, there was $38.2 million of total unrecognized compensation cost related to the Company's unvested stock option and restricted stock grants. This cost is expected to be recognized over a weighted-average period of 2.3 years.

The following table summarizes stock option activity for the nine months ended September 30, 2013 and provides information for options outstanding as of September 30, 2013:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2012	3,649,520	$ 29.84
Granted	26,010	38.76
Exercised	(705,991)	9.60
Forfeited or expired	(55,756)	37.47

Outstanding at September 30, 2013	2,913,783	34.68
Exercisable at September 30, 2013	1,699,151	$ 34.06

The following table summarizes restricted stock activity for the nine months ended September 30, 2013 and provides information for unvested shares as of September 30, 2013:

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2012	1,117,515	$ 35.64
Granted	32,346	37.53
Vested	(30,884)	36.19
Forfeited	(58,560)	35.77
Unvested shares at September 30, 2013	1,060,417	$ 35.67

(15) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced natural gas volumes and through gathering fees associated with the transportation of natural gas to market.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the 2012 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense and interest and other income (loss). The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration and Production (in thousands)	Midstream Services	Other	Total
Three months ended September 30, 2013:				
Revenues from external customers	$ 621,833	$ 246,501	$ 32	$ 868,366
Intersegment revenues	644	601,104	64	601,812
Operating income (loss)	222,692	86,658	(121)	309,229
Other income (loss), net	143	70	(532)	(319)
Gain on derivatives	10,885	1,232	7	12,124
Depreciation, depletion and amortization expense	191,860	12,970	104	204,934
Interest expense(2)	8,580	2,294	144	11,018
Provision (benefit) for income taxes(2)	87,779	36,671	(301)	124,149
Assets	6,264,845	1,387,765	241,778 (3)	7,894,388
Capital investments(4)	496,331	40,052	5,726	542,109
Three months ended September 30, 2012:				
Revenues from external customers	$ 499,083	$ 192,619	$ 25	$ 691,727
Intersegment revenues	(982)	409,720	825	409,563
Operating income (loss)(1)	(141,865)	75,488	418	(65,959)
Other income (loss), net	213	27	(2)	238
Loss on derivatives	(5,879)	–	–	(5,879)
Depreciation, depletion and amortization expense	192,994	10,620	321	203,935
Impairment of natural gas and oil properties	289,821	–	–	289,821
Interest expense(2)	6,707	3,659	240	10,606

Provision (benefit) for income taxes(2)	(55,220)	27,006	61	(28,153)
Assets	5,854,055	1,158,638	343,869 (3)	7,356,562
Capital investments(4)	385,585	31,693	7,608	424,886

	Exploration and Production	Midstream Services	Other	Total
	(in thousands)			
Nine months ended September 30, 2013:				
Revenues from external customers	$ 1,748,821	$ 715,155	$ 80	$ 2,464,056
Intersegment revenues	3,817	1,740,132	177	1,744,126
Operating income (loss)	650,996	235,854	(344)	886,506
Other income (loss), net	61	(27)	(532)	(498)
Gain on derivatives	74,540	1,232	7	75,779
Depreciation, depletion and amortization expense	533,577	37,377	314	571,268
Interest expense(2)	21,101	7,682	534	29,317
Provision (benefit) for income taxes(2)	282,231	91,785	(559)	373,457
Assets	6,264,845	1,387,765	241,778 (3)	7,894,388
Capital investments(4)	1,602,885	135,425	16,748	1,755,058
Nine months ended September 30, 2012:				
Revenues from external customers	$ 1,400,749	$ 551,796	$ 93	$ 1,952,638
Intersegment revenues	(1,716)	1,085,392	2,459	1,086,135
Operating income (loss)(1)	(745,533)	216,598	1,256	(527,679)
Other income (loss), net	(34)	4	2,645	2,615
Loss on derivatives	(10,593)	–	–	(10,593)
Depreciation, depletion and amortization expense	571,934	32,499	959	605,392
Impairment of natural gas and oil properties	1,090,473	–	–	1,090,473
Interest expense(2)	14,459	10,904	942	26,305
Provision (benefit) for income taxes(2)	(289,875)	78,268	1,126	(210,481)
Assets	5,854,055	1,158,638	343,869 (3)	7,356,562
Capital investments(4)	1,450,569	105,576	30,486	1,586,631

(1) The operating loss for the E&P segment for the three and nine months ended September 30, 2012 includes a $289.8 million and $1,090.5 million non-cash ceiling test impairment of our natural gas and oil properties respectively.

(2) Interest expense and the provision for income taxes by segment are allocated as they are incurred at the corporate level.

(3) Other assets represent corporate assets not allocated to segments and assets, including restricted cash and investments in cash equivalents, for non reportable segments.

(4) Capital investments includes decreases of $14.6 million and $56.2 million for the three-month periods ended September 30, 2013 and 2012, respectively, and increase of $25.8 million and decrease of $40.7 million for the nine-month periods ended September 30, 2013 and 2012, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $515.3 million and $332.1 million for the three months ended September 30, 2013 and 2012, respectively, and $1,493.8 million and $863.7 million for the nine months ended September 30, 2013 and 2012, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, restricted cash, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. For the three months ended September 30, 2013 and 2012, capital investments within the E&P segment include $11.9 million and $2.2 million, respectively, related to the Company's activities in Canada. For the nine months ended September 30, 2013 and 2012, capital investments within the E&P segment include $19.8 million and $6.9 million, respectively, relating to the Company's activities in Canada. At September 30, 2013, E&P segment assets include $64.8 million and at September 30, 2012, assets include $36.4 million related to the Company's activities in Canada.

(16) NEW ACCOUNTING PRONOUNCEMENTS ADOPTED

In February 2013, the FASB issued Accounting Standards Update No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income ("Update 2013-02"), which finalizes proposed ASU No. 2012-240, and seeks to improve the transparency of reporting reclassifications out of accumulated other comprehensive income. Update 2013-02 replaces the presentation requirements in ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, and ASU No. 2011-12, Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05. Update 2013-02 requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under U.S. GAAP to be reclassified in its entirety to net income. For public entities, Update 2013-02 is effective prospectively for reporting periods beginning after December 15, 2012, with early adoption permitted. The implementation of the disclosure requirement did not have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In January 2013, the FASB issued Accounting Standards Update No. 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities ("Update 2013-01"), which finalizes Proposed ASU No. 2012-250 and clarifies the scope of transactions that are subject to disclosures concerning offsetting. Update 2013-01 addresses implementation issues regarding the scope of ASU No. 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities, issued in December 2011. Update 2013-01 clarifies that the scope of the disclosures under U.S. GAAP is limited to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are offset either in accordance with FASB ASC Section 210-20-45, Balance Sheet—Offsetting—Other Presentation Matters, or FASB ASC Section 815-10-45, Derivatives and Hedging—Overall—Other Presentation Matters, or are subject to a master netting arrangement or similar agreement. Update 2013-01 requires an entity (1) to apply the amendments for annual reporting periods beginning on or after January 1, 2013 and (2) to provide the required disclosures retrospectively for all comparative periods presented. The implementation of the disclosure requirement did not have a material impact on the Company's consolidated results of operations, financial position or cash flows.

(17) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company is providing condensed consolidating financial information for SEECO, SEPCO and SES, its subsidiaries that are currently guarantors of the Company's registered public debt, and for its other subsidiaries that are not guarantors of such debt. These wholly owned subsidiary guarantors have jointly and severally, fully and unconditionally guaranteed the Company’s 7.35% Senior Notes, 7.125% Senior Notes, and 4.10% Senior Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated to any future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors.

The Company has not presented separate financial and narrative information for each of the subsidiary guarantors because it believes that such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantees. The following condensed consolidating financial information summarizes the results of operations, financial position and cash flows for the Company’s guarantor and non-guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
	(in thousands)				
Three months ended September 30, 2013:					
Operating revenues	$ –	$ 823,112	$ 130,998	$ (85,744)	$ 868,366
Operating costs and expenses:					
Gas purchases – midstream services	–	195,437	–	(166)	195,271
Operating expenses	–	140,400	35,425	(85,556)	90,269
General and administrative expenses	–	43,836	7,155	(22)	50,969
Depreciation, depletion and amortization	–	191,972	12,962	–	204,934
Taxes, other than income taxes	–	15,348	2,346	–	17,694
Total operating costs and expenses	–	586,993	57,888	(85,744)	559,137
Operating income	–	236,119	73,110	–	309,229
Other income (loss), net	–	145	(464)	–	(319)
Gain on derivatives	–	10,251	1,873	–	12,124
Equity in earnings of subsidiaries	185,867	–	–	(185,867)	–
Interest expense	–	9,359	1,659	–	11,018
Income before income taxes	185,867	237,156	72,860	(185,867)	310,016
Provision for income taxes	–	91,466	32,683	–	124,149
Net income	185,867	145,690	40,177	(185,867)	185,867
Comprehensive income	$ 139,179	$ 98,102	$ 40,811	$ (138,913)	$ 139,179

Three months ended September 30, 2012:					
Operating revenues	$ –	$ 647,961	$ 121,343	$ (77,577)	$ 691,727
Operating costs and expenses:					
Gas purchases – midstream services	–	149,765	–	(114)	149,651
Operating expenses	–	106,293	32,277	(76,664)	61,906
General and administrative expenses	–	30,818	6,102	(799)	36,121
Depreciation, depletion and amortization	–	193,057	10,878	–	203,935
Impairment of natural gas and oil properties	–	289,821	–	–	289,821
Taxes, other than income taxes	–	13,513	2,739	–	16,252
Total operating costs and expenses	–	783,267	51,996	(77,577)	757,686
Operating income (loss)	–	(135,306)	69,347	–	(65,959)
Other income, net	–	216	22	–	238
Loss on derivatives	–	(5,879)	–	–	(5,879)
Equity in earnings of subsidiaries	(54,053)	–	–	54,053	–
Interest expense	–	7,200	3,406	–	10,606
Income (loss) before income taxes	(54,053)	(148,169)	65,963	54,053	(82,206)
Provision (benefit) for income taxes	–	(53,903)	25,750	–	(28,153)
Net income (loss)	(54,053)	(94,266)	40,213	54,053	(54,053)
Comprehensive income (loss)	$ (183,944)	$ (225,408)	$ 41,210	$ 184,198	$ (183,944)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
	(in thousands)				
Nine months ended September 30, 2013:					
Operating revenues	$ –	$ 2,331,343	$ 379,212	$ (246,499)	$ 2,464,056
Operating costs and expenses:					
Gas purchases – midstream services	–	576,185	–	(848)	575,337
Operating expenses	–	375,721	106,520	(245,593)	236,648
General and administrative expenses	–	116,648	19,164	(58)	135,754
Depreciation, depletion and amortization	–	533,876	37,392	–	571,268
Taxes, other than income taxes	–	50,053	8,490	–	58,543
Total operating costs and expenses	–	1,652,483	171,566	(246,499)	1,577,550
Operating income	–	678,860	207,646	–	886,506
Other income (loss), net	–	67	(565)	–	(498)
Gain on derivatives	–	73,906	1,873	–	75,779
Equity in earnings of subsidiaries	559,013	–	–	(559,013)	–
Interest expense	–	23,884	5,433	–	29,317
Income before income taxes	559,013	728,949	203,521	(559,013)	932,470
Provision for income taxes	–	291,795	81,662	–	373,457
Net income	559,013	437,154	121,859	(559,013)	559,013
Comprehensive income	$ 457,967	$ 337,122	$ 120,045	$ (457,167)	$ 457,967
Nine months ended September 30, 2012:					
Operating revenues	$ –	$ 1,824,594	$ 350,064	$ (222,020)	$ 1,952,638
Operating costs and expenses:					
Gas purchases – midstream services	–	424,425	–	(484)	423,941
Operating expenses	–	311,165	87,461	(219,148)	179,478
General and administrative expenses	–	111,567	20,700	(2,388)	129,879
Depreciation, depletion and amortization	–	572,139	33,253	–	605,392
Impairment of natural gas and oil properties	–	1,090,473	–	–	1,090,473
Taxes, other than income taxes	–	42,159	8,995	–	51,154
Total operating costs and expenses	–	2,551,928	150,409	(222,020)	2,480,317
Operating income (loss)	–	(727,334)	199,655	–	(527,679)
Other income (loss), net	–	(23)	2,638	–	2,615
Loss on derivatives	–	(10,593)	–	–	(10,593)
Equity in earnings of subsidiaries	(351,481)	–	–	351,481	–
Interest expense	–	15,460	10,845	–	26,305
Income (loss) before income taxes	(351,481)	(753,410)	191,448	351,481	(561,962)

Provision (benefit) for income taxes	–	(285,231)	74,750	–	(210,481)
Net income (loss)	(351,481)	(468,179)	116,698	351,481	(351,481)
Comprehensive income (loss)	$ (567,869)	$ (686,291)	$ 117,660	$ 568,631	$ (567,869)

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
	(in thousands)				
September 30, 2013:					
ASSETS					
Cash and cash equivalents	$ 17,956	$ –	$ 994	$ –	$ 18,950
Accounts receivable	3,114	423,418	18,191	–	444,723
Inventories	–	40,906	2,319	–	43,225
Other assets	13,893	212,154	7,030	–	233,077
Total current assets	34,963	676,478	28,534	–	739,975
Intercompany receivables	2,548,900	57	54,531	(2,603,488)	–
Property and equipment	236,324	13,079,991	1,507,238	–	14,823,553
Less: Accumulated depreciation, depletion and amortization	(102,706)	(7,455,008)	(229,106)	–	(7,786,820)
	133,618	5,624,983	1,278,132	–	7,036,733
Investments in subsidiaries (equity method)	2,788,544	–	–	(2,788,544)	–
Other assets	32,103	69,697	15,880	–	117,680
Total assets	$ 5,538,128	$ 6,371,215	$ 1,377,077	$ (5,392,032)	$ 7,894,388
LIABILITIES AND EQUITY					
Accounts payable	$ 147,265	$ 432,089	$ 84,372	$ –	$ 663,726
Other current liabilities	3,759	141,307	1,019	–	146,085
Total current liabilities	151,024	573,396	85,391	–	809,811
Intercompany payables	–	2,603,488	–	(2,603,488)	–
Long-term debt	1,911,165	–	–	–	1,911,165
Deferred income taxes	(115,675)	1,077,055	427,453	–	1,388,833
Other liabilities	71,625	178,703	14,262	–	264,590
Total liabilities	2,018,139	4,432,642	527,106	(2,603,488)	4,374,399
Commitments and contingencies					
Total equity	3,519,989	1,938,573	849,971	(2,788,544)	3,519,989

Total liabilities and equity	$ 5,538,128	$ 6,371,215	$ 1,377,077	$ (5,392,032)	$ 7,894,388

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
	(in thousands)				
December 31, 2012:					
ASSETS					
Cash and cash equivalents	$ 47,491	$ 5,988	$ 104	$ –	$ 53,583
Restricted cash	8,542	–	–	–	8,542
Accounts receivable	2,677	353,607	21,354	–	377,638
Inventories	2	26,975	1,164	–	28,141
Other assets	7,461	321,396	12,151	–	341,008
Total current assets	66,173	707,966	34,773	–	808,912
Intercompany receivables	2,259,713	42	27,077	(2,286,832)	–
Property and equipment	220,837	11,491,222	1,316,380	–	13,028,439
Less: Accumulated depreciation, depletion and amortization	(82,178)	(6,923,106)	(186,179)	–	(7,191,463)
	138,659	4,568,116	1,130,201	–	5,836,976
Investments in subsidiaries (equity method)	2,309,947	–	–	(2,309,947)	–
Other assets	35,136	42,247	14,256	–	91,639
Total assets	$ 4,809,628	$ 5,318,371	$ 1,206,307	$ (4,596,779)	$ 6,737,527
LIABILITIES AND EQUITY					
Accounts payable	$ 140,367	$ 375,604	$ 41,009	$ –	$ 556,980
Other current liabilities	3,758	205,623	1,410	–	210,791
Total current liabilities	144,125	581,227	42,419	–	767,771
Intercompany payables	–	2,108,360	178,472	(2,286,832)	–
Long-term debt	1,668,273	–	–	–	1,668,273
Deferred income taxes	(116,207)	820,279	345,066	–	1,049,138
Other liabilities	77,565	124,505	14,403	–	216,473
Total liabilities	1,773,756	3,634,371	580,360	(2,286,832)	3,701,655
Commitments and contingencies					
Total equity	3,035,872	1,684,000	625,947	(2,309,947)	3,035,872

Total liabilities and equity	$ 4,809,628	$ 5,318,371	$ 1,206,307	$ (4,596,779)	$ 6,737,527

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CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent (in thousands)	Guarantors	Non-Guarantors	Eliminations	Consolidated
Nine months ended September 30, 2013:					
Net cash provided by (used in) operating activities	$ (32,502)	$ 1,062,133	$ 347,887	$ –	$ 1,377,518
Investing activities:					
Capital investments	(29,227)	(1,530,760)	(167,556)	–	(1,727,543)
Proceeds from sale of property and equipment	–	210	2,871	–	3,081
Transfers from restricted cash	8,542	–	–	–	8,542
Other	(74)	(1,685)	6,459	–	4,700
Net cash used in investing activities	(20,759)	(1,532,235)	(158,226)	–	(1,711,220)
Financing activities:					
Intercompany activities	(274,931)	464,114	(189,183)	–	–
Payments on current portion of long-term debt	(600)	–	–	–	(600)
Payments on revolving long-term debt	(2,134,550)	–	–	–	(2,134,550)
Borrowing under revolving long-term debt	2,377,950	–	–	–	2,377,950
Other Items	55,857	–	–	–	55,857
Net cash provided by (used in) financing activities	23,726	464,114	(189,183)	–	298,657
Effect of exchange rate changes on cash	–	–	412	–	412
Increase (decrease) in cash and cash equivalents	(29,535)	(5,988)	890	–	(34,633)
Cash and cash equivalents at beginning of year	47,491	5,988	104	–	53,583
Cash and cash equivalents at end of period	$ 17,956	$ –	$ 994	$ –	$ 18,950
Nine months ended September 30, 2012:					
Net cash provided by (used in) operating activities	$ (55,324)	$ 915,885	$ 331,916	$ –	$ 1,192,477
Investing activities:					
Capital investments	(38,946)	(1,452,061)	(132,744)	–	(1,623,751)
	144	169,149	31,868	–	201,161

Proceeds from sale of property and equipment					
Transfers to restricted cash	(167,774)	–	–	–	(167,774)
Transfers from restricted cash	40,700	–	–	–	40,700
Other	16,575	(24,340)	13,004	–	5,239
Net cash used in investing activities	(149,301)	(1,307,252)	(87,872)	–	(1,544,425)
Financing activities:					
Intercompany activities	(148,027)	392,732	(244,705)	–	–
Payments on current portion of long-term debt	(600)	–	–	–	(600)
Payments on revolving long-term debt	(1,774,000)	–	–	–	(1,774,000)
Borrowings under revolving long-term debt	1,129,000	–	–	–	1,129,000
Proceeds from issuance of long-term debt	998,780	–	–	–	998,780
Other items	1,722	–	(11)	–	1,711
Net cash provided by (used in) financing activities	206,875	392,732	(244,716)	–	354,891
Effect of exchange rate changes on cash	–	–	(10)	–	(10)
Increase (decrease) in cash and cash equivalents	2,250	1,365	(682)	–	2,933
Cash and cash equivalents at beginning of year	14,711	–	916	–	15,627
Cash and cash equivalents at end of period	$ 16,961	$ 1,365	$ 234	$ –	$ 18,560

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ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following updates information as to Southwestern Energy Company’s financial condition provided in our 2012 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2013 and 2012. For definitions of commonly used natural gas and oil terms used in this Form 10-Q, please refer to the “Glossary of Certain Industry Terms” provided in our 2012 Annual Report on Form 10-K.

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in the “Cautionary Statement About Forward-Looking Statements” in the forepart of this Form 10-Q, in Item 1A, “Risk Factors” in Part I and elsewhere in our 2012 Annual Report on Form 10-K, and Item 1A, “Risk Factors” in Part II in this Form 10-Q and any other Form 10-Q filed during the fiscal year. You should read the following discussion with our unaudited condensed consolidated financial statements and the related notes included in this Form 10-Q.

OVERVIEW

Background

Southwestern Energy Company is an independent energy company engaged in natural gas and oil exploration, development and production, or E&P. We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration for and production of natural gas and oil, with our current operations being focused within the United States. We are actively engaged in exploration and production activities in Arkansas, where we are targeting the unconventional gas reservoir known as the Fayetteville Shale, in Pennsylvania, where we are targeting the unconventional gas reservoir known as the Marcellus Shale, and to a lesser extent in Texas and in

Arkansas and Oklahoma in the Arkoma Basin. We have recently commenced exploration operations in Arkansas and Louisiana testing an unconventional oil play targeting the Lower Smackover Brown Dense, or LSBD formation, as well as in Colorado. In 2010, we commenced an exploration program in New Brunswick, Canada, which represents our first operations outside of the United States.

We are focused on providing long-term growth in the net asset value of our business. We derive the majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will depend primarily on natural gas prices and our ability to increase our natural gas production. We expect our natural gas production volumes will continue to increase due to our ongoing development of the Fayetteville Shale play and the Marcellus Shale play. The price we expect to receive for our natural gas is a critical factor in the capital investments we make in order to develop our properties and increase our production. In recent years, there has been volatility in natural gas prices as evidenced by New York Mercantile Exchange, or NYMEX, natural gas prices ranging from a high of $13.58 per MMBtu in 2008 to a recent low of $1.91 per MMBtu in April 2012. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sale prices for our production. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices.

Three Months Ended September 30, 2013 Compared with Three Months Ended September 30, 2012

We reported net income of $185.9 million for the three months ended September 30, 2013, or $0.53 per diluted share, compared to a net loss of $54.1 million, or $0.16 per diluted share, for the comparable period in 2012.

Our natural gas and oil production increased to 172.4 Bcfe for the three months ended September 30, 2013, up 19% from 144.3 Bcfe for the three months ended September 30, 2012. The 28.1 Bcfe increase in our third quarter 2013 production was primarily due to a 29.6 Bcf increase in net production from our Marcellus Shale properties and a 1.5 Bcf decrease in net production from our other properties. The average price realized for our gas production, including the effects of hedges, increased 6% to $3.60 per Mcf for the three months ended September 30, 2013 compared to $3.41 per Mcf for the same period in 2012.

Our E&P segment reported operating income of $222.7 million for the three months ended September 30, 2013, up from an operating loss of $141.9 million for the three months ended September 30, 2012. The loss for the three months ended September 30, 2012 included a $289.8 million non-cash ceiling test impairment of our natural gas and oil properties. Excluding the $289.8 non-cash ceiling test impairment, operating income for the three months ended September 30, 2013 increased $74.7 million as a result of an increase in revenue of $96.0 million from higher natural gas production volumes and an increase in revenue of $25.8 million from increased prices from the sale of our natural gas production, offset by an increase in operating costs and expenses of $49.6 million associated with the expansion of our E&P operations due to the continued development of our Fayetteville Shale play and Marcellus Shale play.

Operating income for our Midstream Services segment was $86.7 million for the three months ended September 30, 2013, up from $75.5 million for the three months ended September 30, 2012, primarily due to an increase of $10.4 million in gas gathering revenues and an increase of $8.2 million in the margin generated from our natural gas marketing activities, which was partially offset by a $7.4 million increase in operating costs and expenses associated with an increase in natural gas volumes gathered, exclusive of natural gas purchase costs.

Capital investments were $542.1 million for the three months ended September 30, 2013, of which $496.3 million was invested in our E&P segment, compared to $424.9 million for the same period of 2012, of which $385.6 million was invested in our E&P segment.

Nine Months Ended September 30, 2013 Compared with Nine Months Ended September 30, 2012

We reported net income of $559.0 million for the nine months ended September 30, 2013, or $1.59 per diluted share, compared to net loss of $351.5 million, or $1.01 per diluted share, for the comparable period in 2012.

Our natural gas and oil production increased to 480.3 Bcfe for the nine months ended September 30, 2013, up 16% from 415.1 Bcfe for the nine months ended September 30, 2012. The 65.2 Bcfe increase in our 2013 production was primarily due to a 67.8 Bcf increase in net production from our Marcellus Shale properties, a 2.4 Bcf increase in net production from our Fayetteville Shale properties, and a 1.2 Bcfe increase from our New Ventures properties, which more than offset a 6.2 Bcfe decrease in net production from our Ark-La-Tex properties primarily due to the sale of certain East Texas oil and natural gas properties in 2012. The average price realized for our gas production, including the effects of hedges, increased 9% to $3.63 per Mcf for the nine months ended September 30, 2013 compared to $3.33 per Mcf for the same period in 2012.

Our E&P segment reported operating income of $651.0 million for the nine months ended September 30, 2013, up from an operating loss of $745.5 million for the nine months ended September 30, 2012. The loss for the nine months ended September 30, 2012 included a $1,090.5 million non-cash ceiling test impairment of our natural gas and oil properties. Excluding the $1,090.5 non-cash ceiling test impairment, operating income for the nine months ended September 30, 2013 increased $306.1 million as a result of an increase in revenue of $217.3 million from higher natural gas production volumes, an increase in revenue of $129.4 million from increased prices realized from the sale of our natural gas production and an increase in revenues of $6.3 million from higher oil and NGL volumes, offset by an increase in operating costs and expenses of $47.5 million associated with the expansion of our E&P operations due to the continued development of our Fayetteville Shale play and Marcellus Shale play.

Operating income for our Midstream Services segment was $235.9 million for the nine months ended September 30, 2013, up from $216.6 million for the nine months ended September 30, 2012, primarily due to an increase of $31.3 million in gas gathering revenues and an increase of $10.9 million in the margin generated from our gas marketing activities, which was partially offset by a $23.0 million increase in operating costs and expenses associated with an increase in gas volumes gathered, exclusive of gas purchase costs.

Net cash provided by operating activities increased 16% to $1,377.5 million for the nine months ended September 30, 2013, up from $1,192.5 million for the same period in 2012, due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher natural gas production and gathering volumes, higher realized gas prices, offset slightly by a decrease in changes in working capital. Capital investments were $1,755.1 million for the nine months ended September 30, 2013, of which $1,602.9 million was invested in our E&P segment, compared to $1,586.6 million for the same period of 2012, of which $1,450.6 million was invested in our E&P segment.

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense, income tax expense and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
Revenues (in thousands)	$ 622,477	$ 498,101	$ 1,752,638	$ 1,399,033
Impairment of natural gas and oil properties (in thousands)	$ –	$ 289,821	$ –	$ 1,090,473
Operating costs and expenses (in thousands)	$ 399,785	$ 350,145	$ 1,101,642	$ 1,054,093
Operating income (loss) (in thousands)	$ 222,692	$ (141,865)	$ 650,996	$ (745,533)
Gain (loss) on derivatives(1)	$ 2,020	$ (4,740)	$ 3,115	$ (11,485)
Gas production (Bcf)	172.1	144.2	479.4	414.7
Oil production (MBbls)	37	19	102	59
NGL production (MBbls)	12	–	40	–
Total production (Bcfe)	172.4	144.3	480.3	415.1
Average realized gas price per Mcf, including hedges (2)	$ 3.60	$ 3.41	$ 3.63	$ 3.33
Average realized gas price per Mcf, excluding hedges	$ 3.06	$ 2.35	$ 3.18	$ 2.12
Average oil price per Bbl	$ 106.72	$ 99.67	$ 105.05	$ 102.89
Average NGL price per Bbl	$ 42.05	$ –	$ 44.20	$ –
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.87	$ 0.79	$ 0.85	$ 0.80
General & administrative expenses	$ 0.24	$ 0.21	$ 0.23	$ 0.26
Taxes, other than income taxes	$ 0.09	$ 0.09	$ 0.10	$ 0.10
Full cost pool amortization	$ 1.07	$ 1.30	$ 1.07	$ 1.34

(1)Represents the commodity mark to market gain (loss) on derivatives, settled, associated with derivatives not designated or not qualifying for hedge accounting.

(2)Had we included the commodity mark to market gain (loss) on derivatives effects of commodity hedging contracts not designated or not qualifying for hedge accounting, our average price for total natural gas would have been $3.67, $3.40, $3.78, and $3.34 per Mcf for the three months ended September 30, 2013 and 2012, and the nine months ended September 30, 2013 and 2012, respectively.

Revenues

Revenues for our E&P segment were $622.5 million for the three months ended September 30, 2013, up $124.4 million, or 25%, compared to the same period in 2012. Higher natural gas production volumes and increased prices realized from the sale of our natural gas production increased revenues by $96.0 million and $25.8 million, respectively. E&P revenues were $1.8 billion for the nine months ended September 30, 2013, up $353.6 million, or 25%. The increase in revenue was driven by a $217.3 million increase from higher natural gas production volumes, a $129.4 million increase from prices realized from the sale of our natural gas production, and a $6.3 million increase from higher oil and NGL volumes. We expect our natural gas production volumes to continue to increase due to our development and growth of our shale properties. Natural gas prices are difficult to predict and subject to wide price fluctuations. As of September 30, 2013, we had hedged 84.4 Bcf of our remaining 2013 natural gas production and 232.7 Bcf of our 2014 natural gas production to limit our exposure to price fluctuations. We refer you to Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q and to the discussion of "Commodity Prices" provided below for additional information.

Production

For the three months ended September 30, 2013, our natural gas and oil production increased 19% to 172.4 Bcfe, up from 144.3 Bcfe from the same period in 2012, and was produced entirely by our properties in the United States. The 28.1 Bcfe increase in our 2013 production was primarily due to a 29.6 Bcf increase in net production from our Marcellus Shale properties and a 1.5 Bcf decrease in net production from our other properties. Net production from our Fayetteville Shale and Marcellus Shale properties was 122.7 Bcf and 44.7 Bcf, respectively, for the three months ended September 30, 2013 compared to 123.6 Bcf and 15.1 Bcf, respectively, for the same period in 2012. For the nine months ended September 30, 2013, our natural gas and oil production increased 16% to 480.3 Bcfe, up from 415.1 Bcfe from the same period in 2012, and was produced entirely by our properties in the United States. The 65.2 Bcfe increase in our 2013 production was primarily due to a 67.8 Bcf increase in net natural gas production from our Marcellus Shale properties, a 2.4 Bcf increase in net production from our Fayetteville Shale play, and a 1.2 Bcfe increase in our New Ventures properties, which more than offset a 6.2 Bcfe decrease in net production from our Ark-La-Tex properties. Net production from our Fayetteville Shale and Marcellus Shale properties was 362.8 Bcf and 102.1 Bcf, respectively, for the nine months ended September 30, 2013 compared to 360.4 Bcf and 34.3 Bcf, respectively, for the same period in 2012.

Commodity Prices

The average realized price for our natural gas production, including the effects of hedges, increased to $3.60 per Mcf for the three months ended September 30, 2013, as compared to $3.41 for the same period in 2012. The increase was the result of a $0.71 per Mcf increase in average natural gas prices, excluding hedges, partially offset by a $0.52 per Mcf decrease in the impact of our price hedging activities. The average price realized for our natural gas production, excluding the effects of hedges, increased 30% to $3.06 per Mcf for the three months ended September 30, 2013, as compared to the same period in 2012. Our hedges increased the average realized natural gas price $0.54 per Mcf for the three months ended September 30, 2013 compared to an increase of $1.06 per Mcf for the same period in 2012. The average price realized for our natural gas production, including the effects of hedges, increased 9% to $3.63 per Mcf for the nine months ended September 30, 2013, as compared to the same period in 2012. The increase in the average price realized for nine months ended September 30, 2013, as compared to the same period in 2012, primarily reflects the $1.06 Mcf increase in average gas prices, excluding hedges, which was partially offset by the $0.76 Mcf decreased effect of our price hedging activities. Our hedging activities increased the average natural gas price $0.45 per Mcf for the nine months ended September 30, 2013 compared to an increase of $1.21 per Mcf for the same period in 2012. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational basis differentials (we refer you to Item 3 and Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion).

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to locational basis differentials, while transportation charges and fuel charges also reduce the price received. Excluding the impact of hedges, the average price received for our natural gas production for the nine months ended September 30, 2013 of $3.18 per Mcf was approximately $0.49 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We protected approximately 51% of our natural gas production for the nine months ended September 30, 2013 from the impact of widening basis differentials through our hedging activities and sales arrangements. For the remainder of 2013, we expect our total natural gas sales discount to NYMEX to be approximately $0.50 to $0.55 per Mcf. At September 30, 2013, we had basis protected on approximately 74 Bcf of our remaining 2013 expected natural gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX natural gas prices of approximately ($0.06) per Mcf, excluding transportation and fuel charges. Additionally, at September 30, 2013, we had basis protected on approximately 141 Bcf and 29 Bcf of our 2014 and 2015 expected natural gas production, respectively, through financial hedging activities and physical sales arrangements.

In addition to the basis hedges discussed above, at September 30, 2013, we had NYMEX fixed price hedges in place on notional volumes of 84.4 Bcf of our remaining 2013 natural gas production at an average price of $4.68 per MMBtu and notional volumes of 232.7 Bcf of our 2014 natural gas production at an average price of $4.41 per MMBtu.

Operating Income

Our E&P segment reported operating income of $222.7 million for the three months ended September 30, 2013, up from an operating loss of $141.9 million for the three months ended September 30, 2012. The loss for the three months ended September 30, 2012 included a $289.8 million non-cash ceiling test impairment of our natural gas and oil properties. Excluding the $289.8 non-cash ceiling test impairment, operating income for the three months ended September 30, 2013 increased $74.7 million as a result of an increase in revenue of $96.0 million from higher natural gas production volumes and an increase in revenue of $25.8 million from increased prices from the sale of our natural gas production, offset slightly by an increase in operating costs and expenses of $49.6 million due to increased compression and gathering costs. Our E&P segment reported operating income of $651.0 million for the nine months ended September 30, 2013, up from an operating loss of $756.1 million for the nine months ended September 30, 2012. The loss for the nine months ended September 30, 2012 included a $1,090.5 million non-cash ceiling test impairment of our natural gas and oil properties. Excluding the $1,090.5 non-cash ceiling test impairment, operating income for the nine months ended September 30, 2013 increased $306.1 million as a result of an increase in revenue of $217.3 million from higher natural gas production volumes, an increase in revenue of $129.4 million from increased prices realized from the sale of our natural gas production, an increase in revenues of $6.3 million from higher oil and NGL volumes, offset by an increase in operating costs and expenses of $47.5 million due primarily to increased compression and gathering costs, reduced slightly by lower salt water disposal costs.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.87 for the three months ended September 30, 2013 compared to $0.79 for the same period in 2012. Lease operating expenses per Mcfe for our E&P segment were $0.85 for the nine months ended September 30, 2013 compared to $0.80 for the same period in 2012. The increase in lease operating expense per unit of production for the three- and nine-months ended September 30, 2013 as compared to the same period of 2012, was primarily due to increase in compression and gathering cost in our Marcellus Shale play, offset slightly by a decrease in salt water disposal cost in our Fayetteville Shale play.

General and administrative expenses per Mcfe for our E&P segment were $0.24 for the three months ended September 30, 2013 compared to $0.21 for the same period in 2012 primarily due to an increase in personnel costs. General and administrative expenses per Mcfe were $0.23 for the nine months ended September 30, 2013 compared to $0.26 for same period in 2012 primarily due to a decrease in personnel costs and increased production volumes. In total general and administrative expenses for our E&P segment were $42.0 million for the three months ended September 30, 2013 compared to $30.3 million for the same period in 2012, primarily due to increased personnel costs and professional fees associated with the expansion of our E&P operations due to the continued development of our Fayetteville Shale play and Marcellus Shale play. In total general and administrative expenses for our E&P segments were $111.6 million for the nine months ended September 30, 2013 compared to $107.6 million for the same period in 2012. The increase in general and administrative expenses for the nine months ended September 30, 2013 as compared to the same period of 2012, was primarily a result of increased professional fees associated with the expansion of our E&P

operations due to the continued development of our Fayetteville Shale play and Marcellus Shale play.

Taxes other than income taxes per Mcfe were $0.09 for the three months ended September 30, 2013 and 2012, and $0.10 for the nine months ended September 30, 2013 and 2012. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $1.07 per Mcfe for the three months ended September 30, 2013 compared to $1.30 for the same period in 2012. For the first nine months of 2013, our full cost pool amortization rate averaged $1.07 per Mcfe compared to $1.34 per Mcfe for the same period in 2012. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserves.

Unevaluated costs excluded from amortization were $1,101.5 million at September 30, 2013 compared to $1,023.9 million at December 31, 2012. The increase in unevaluated costs since December 31, 2012 primarily resulted from our acquisition of Marcellus acreage in the second quarter 2013 and an increase in our wells in progress. Unevaluated costs excluded from amortization at September 30, 2013 included $58.7 million related to our properties in Canada, compared to $40.4 million at December 31, 2012.

The timing and amount of production and reserve additions and revisions could have a material adverse impact on our per unit costs.

Midstream Services

	For the three months ended September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
	($ in thousands, except volumes)			
Revenues – marketing	$ 716,703	$ 481,845	$ 2,076,590	$ 1,289,818
Revenues – gathering	$ 130,902	$ 120,494	$ 378,697	$ 347,370
Gas purchases – marketing	$ 701,304	$ 474,628	$ 2,042,948	$ 1,267,117
Operating costs and expenses	$ 59,643	$ 52,223	$ 176,485	$ 153,473
Operating income	$ 86,658	$ 75,488	$ 235,854	$ 216,598
Gas volumes marketed (Bcf)	206.4	171.2	574.9	498.7
Gas volumes gathered (Bcf)	229.9	214.7	667.3	622.9

Revenues

Revenues from our marketing activities were up 49% to $716.7 million for the three months ended September 30, 2013 and were up 61% to $2,076.6 million for the nine months ended September 30, 2013 compared to the same period in 2012. For the three months ended September 30, 2013, the volumes marketed increased 21% and the price received for volumes marketed increased 23% compared to the same period in 2012. For the nine months ended September 30, 2013, the volumes marketed increased 15% and the price received for volumes marketed increased 39% compared to the same period in 2012. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Of the total volumes marketed, production from our affiliated E&P operated wells accounted for 95% and 96% of the marketed volumes for the three months ended September 30, 2013 and 2012, respectively. For the nine months ended September 30, 2013 and 2012, production from our affiliated E&P operated wells accounted for 96% and 95% of the marketed volumes, respectively.

Revenues from our gathering activities were up 9% to $130.9 million for the three months ended September 30, 2013 and up 9% to $378.7 million for the nine months ended September 30, 2013 compared to respective periods in 2012. The increase in gathering revenues resulted primarily from a 7% increase in gas volumes gathered for the three months ended September 30, 2013 and the nine months ended September 30, 2013, respectively, compared to the same period in 2012. A majority of the increase in gathering revenues for the three- and nine-months ended September 30, 2013 resulted from increases in volumes gathered due to our development and growth of our shale properties. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to our shale properties are developed and production increases.

Operating Income

Operating income from our Midstream Services segment increased to $86.7 million for the three months ended September 30, 2013 compared to $75.5 million for the same period in 2012 and increased to $235.9 million for the nine months ended September 30, 2013 compared to $216.6 million for the same period in 2012. Operating income was higher due to increases in gas volumes gathered which primarily resulted from our increase in E&P production volumes. The $11.2 million increase in operating income for the three months ended September 30, 2013 was primarily due to an increase of $10.4 million in gathering revenues and an increase of $8.2 million in the margin generated from our gas marketing activities, which was partially offset by a $7.4 million increase in operating costs and expenses associated with an increase in gas volumes gathered, exclusive of gas purchase costs. The $19.3 million increase in operating income for the nine months ended September 30, 2013 was primarily due to an increase of $31.3 million in gathering revenues and an increase of $10.9 million in the margin generated from our gas marketing activities, which was partially offset by a $23.0 million increase in operating costs and expenses, exclusive of gas purchase costs, associated with the increase in gas volumes gathered.

The margin generated from gas marketing activities was $15.4 million for the three months ended September 30, 2013 compared to $7.2 million for the three months ended September 30, 2012. The margin generated from gas marketing activities was $33.6 million for the nine months ended September 30, 2013 compared to $22.7 million for the nine months ended September 30, 2012. Margins are primarily driven by volumes of natural gas marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. We enter into hedging activities from time to time with respect to our natural gas marketing activities to provide margin protection. We refer you to Item 3, “Quantitative and Qualitative Disclosures about Market Risks” included in this Form 10-Q for additional information.

Interest Expense

Interest expense, net of capitalization, increased to $11.0 million for the three months ended September 30, 2013, compared to $10.6 million for the same period in 2012 and increased to $29.3 million for the nine months ended September 30, 2013 compared to $26.3 million for the same period in 2012. The increase in interest expense, net of capitalization, for the three months ended September 30, 2013 was primarily due to a decrease in capitalized interest for the three months ended September 30, 2013. The increase in interest expense, net of capitalization, for the nine-month period ended September 30, 2013 was primarily due to our increased borrowing level, partially offset by an increase in capitalized interest for the nine months ended September 30, 2013. We capitalized interest of $15.5 and $15.9 million for the three months ended September 30, 2013 and 2012, respectively. The decrease in capitalized interest for the three months ending September 30, 2013 compared to the same period in 2012 was primarily due to a decrease to the Company’s weighted average borrowing rate. We capitalized interest of $48.5 and $45.9 million for and nine-month periods ended September 30, 2013 and 2012, respectively. The increase in capitalized interest for the nine-month period ending September 30, 2013 compared to the same period in 2012 was primarily due to the increase in our unevaluated property balance during 2013.

Gain (Loss) on Derivatives

At September 30, 2013, our basis swaps did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gain (loss) on derivatives. For the nine months ended September 30, 2013, we recorded a mark to market loss on derivatives of $26.9 million related to fixed price call options that did not qualify for hedge accounting treatment, a mark to market gain on derivatives of $96.6 million related to fixed price swaps not designated for hedge accounting, and a mark to market gain on derivatives of $1.6 million related to the basis swaps that did not qualify for hedge accounting treatment. In general and without consideration of volatility or duration, as 2014 natural gas prices increase from current levels, the Company will recognize losses in future periods and, likewise, as 2014 natural gas prices decline from current levels, the Company will recognize gains in future periods on its derivative contracts not accounted for under hedge accounting prior to settlement.

Income Taxes

Our effective tax rates were 40.0% and 37.5% for the nine months ended September 30, 2013 and 2012, respectively. For the nine months ended September 30, 2013, we recorded an income tax expense of $373.5 million compared to an income tax benefit of $210.5 million for the same period in 2012.

Stock-Based Compensation Expense

We recognized expense of $2.9 million and capitalized $2.8 million for stock-based compensation during the three months ended September 30, 2013 compared to $2.7 million expense and $2.5 million capitalized for the comparable period in 2012. We recognized expense of $8.9 million and capitalized $8.5 million for stock-based compensation costs recognized during the nine-month period ended September 30, 2013 compared to $8.2 million expense and $7.8 million capitalized for the comparable period in 2012. We refer you to Note 14 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

New Accounting Standards

In February 2013, the FASB issued Accounting Standards Update No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income ("Update 2013-02"), which finalizes proposed ASU No. 2012-240, and seeks to improve the transparency of reporting reclassifications out of accumulated other comprehensive income. Update 2013-02 replaces the presentation requirements in ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, and ASU No. 2011-12, Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05. Update 2013-02 requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under U.S.

GAAP to be reclassified in its entirety to net income. For public entities, Update 2013-02 is effective prospectively for reporting periods beginning after December 15, 2012, with early adoption permitted. The implementation of the disclosure requirement did not have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In January 2013, the FASB issued Accounting Standards Update No. 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities ("Update 2013-01"), which finalizes Proposed ASU No. 2012-250 and clarifies the scope of transactions that are subject to disclosures concerning offsetting. Update 2013-01 addresses implementation issues regarding the scope of ASU No. 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities, issued in December 2011. Update 2013-01 clarifies that the scope of the disclosures under U.S. GAAP is limited to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are offset either in accordance with FASB ASC Section 210-20-45, Balance Sheet—Offsetting—Other Presentation Matters, or FASB ASC Section 815-10-45, Derivatives and Hedging—Overall—Other Presentation Matters, or are subject to a master netting arrangement or similar agreement. Update 2013-01 requires an entity (1) to apply the amendments for annual reporting periods beginning on or after January 1, 2013 and (2) to provide the required disclosures retrospectively for all comparative periods presented. The implementation of the disclosure requirement did not have a material impact on the Company's consolidated results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our Credit Facility and funds accessed through debt and equity markets as our primary sources of liquidity.

For the remainder of 2013, assuming natural gas prices remain at current levels, we intend to draw on a portion of the funds available under our Credit Facility to fund our planned capital investments (discussed below under "Capital Investments"). We refer you to Note 10 to the unaudited condensed consolidated financial statements included in this Form 10-Q and the section below under "Financing Requirements" for additional discussion of our Credit Facility.

Net cash provided by operating activities increased 16% to $1,377.5 million for the nine months ended September 30, 2013 compared to $1,192.5 million for the same period in 2012, is primarily due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher realized gas prices, higher natural gas production and gathering volumes, offset slightly by a decrease in changes in working capital. During the nine months ended September 30, 2013, requirements for our capital investments were funded primarily from our cash generated by operating activities, cash and cash equivalents, and net proceeds from borrowings under our Credit Facility. For the nine months ended September 30, 2013, cash generated from our operating activities funded 80% of our cash requirements for capital investments and 73% for the nine months ended September 30, 2012.

We believe that our operating cash flow, cash equivalents, and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for 2013. The credit status of the financial institutions participating in our Credit Facility could adversely impact our ability to borrow funds under the Credit Facility. While we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet its obligation.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our natural gas and oil production, including regional basis differentials. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors which are impacted by the overall state of the economy. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Item 3, “Quantitative and Qualitative Disclosures about Market Risks” and Note 7 in the unaudited condensed consolidated financial statements included in this Form 10-Q. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and partners. We actively manage this risk through credit management activities and through the date of this filing have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

Due to the above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow.

Capital Investments

Our capital investments were $1.8 billion for the nine months ended September 30, 2013 compared to $1.6 billion for the comparable period in 2012. Our E&P segment investments were $1.6 billion and $1.5 billion for the nine months ended September 30, 2013 and 2012 respectively. Our E&P segment capitalized internal costs of $136.9 million for the nine months ended September 30, 2013 compared to $113.1 million for the comparable period in 2012. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties.

Our capital investments for 2013 are planned to be approximately $2.25 billion, consisting of $2.0 billion for E&P, $160 million for Midstream Services and $90 million for corporate and other purposes. Of the approximate $2.0 billion for E&P, we expect to allocate approximately $900 million to our Fayetteville Shale play and approximately $870 million to our Marcellus Shale play. Our planned level of capital investments in 2013 is expected to allow us to continue our progress in the Fayetteville Shale and Marcellus Shale programs and explore and develop other existing natural gas and oil properties and generate new drilling prospects. Our remaining 2013 capital investment program is expected to be funded through cash flow from operations and borrowings under our revolving credit facility. The planned capital program for 2013 is flexible and can be modified. We will reevaluate our proposed investments as needed to take into account prevailing market conditions and we could change our planned investments.

Financing Requirements

Our total debt outstanding was $1.9 billion at September 30, 2013 compared to $1.7 billion at December 31, 2012. In February 2011, we amended and restated our unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016. The amount available under the revolving credit facility may be increased to $2.0 billion at any time upon the Company’s agreement with its existing or additional lenders. We had $243.4 million outstanding under our revolving credit facility at September 30, 2013 compared to no borrowings on our credit facility at December 31, 2012.

The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 200 basis points over LIBOR. Our publicly traded notes are rated BBB- by Standard and Poor’s and we have a long term debt rating of Baa3 by Moody’s. Any downgrades in our public debt ratings could increase our cost of funds under the Credit Facility.

Our Credit Facility contains covenants which impose certain restrictions on us. Under the Credit Facility, we must keep our total debt at or below 60% of our total capital, and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Our Credit Facility's financial covenants with respect to capitalization percentages exclude hedging activities, pension and other postretirement liabilities as well as the effects of non-cash entries that result from any full cost ceiling impairments occurring after the date of the agreement. At September 30, 2013, our capital structure as determined under our Credit Facility was 30% debt and 70% equity, which excluded hedging activities, pension and other postretirement liabilities, and if applicable, the effect of the non-cash full cost ceiling impairment. We were in compliance with all of the covenants of our Credit Facility at September 30, 2013. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our Credit Facility, we may have to decrease our capital investment plans.

In March 2012, we issued $1 billion of 4.10% Senior Notes due 2022 in a private placement. A portion of the net proceeds of the offering were used to repay the amounts outstanding under the Company's revolving credit facility and the remaining proceeds were used for general corporate purposes.

At September 30, 2013 and December 31, 2012, our capital structure consisted of 35% debt and 65% equity (exclusive of cash and cash equivalents and restricted cash) and $18.9 and $62.1 million in cash and cash equivalents and restricted cash, respectively. Equity at September 30, 2013 included an accumulated other comprehensive gain of $72.1 million related to our hedging activities, partially offset by $21.5 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on current market values for our hedges at September 30, 2013 and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At September 30, 2013, we had NYMEX commodity price hedges in place on 84.4 Bcf of our remaining targeted 2013 natural gas production and 232.7 Bcf of our expected 2014 natural gas production. The amount of long-term debt we incur will be largely dependent upon commodity prices and our capital investment plans.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations from those disclosed in our 2012 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately $47 million in the aggregate over a three year period. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $44.5 million Canadian dollars. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of September 30, 2013 had invested $35.4 million in New Brunswick towards the Company’s commitment. In December 2012, we received two one-year extensions to our exploration license agreements which expire on March 16, 2014 and March 16, 2015, respectively. No liability has been recognized in connection with the promissory notes due to the Company’s investments in New Brunswick as of September 30, 2013 and its future investment plans.

Substantially all of our employees are covered by defined pension and postretirement benefit plans. As of September 30, 2013, the Company has contributed $9.0 million to the pension plan and $0.1 million to the postretirement benefit plan, and expects to contribute an additional $3.0 million to the pension plan in 2013. At September 30, 2013, we recognized a liability of $35.3 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $33.5 million at December 31, 2012.

We are subject to litigation, claims and proceedings (including with respect to environmental matters) that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position, results of operations, or cash flows, but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. For further information regarding commitments and contingencies, we refer you to Note 11 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Working Capital

We had negative working capital of $69.8 million at September 30, 2013 and positive working capital of $41.1 million at December 31, 2012. Current assets decreased by $68.9 million during the nine months ended September 30, 2013 primarily due to an $85.0 million decrease in current hedging asset, a $43.2 million decrease in cash, cash equivalents and restricted cash, and a $22.9 million decrease in other current assets. These decreases were partially offset by a $67.1 million increase in accounts receivable and a $15.1 million increase in inventory. Current liabilities increased by $42.0 million during the nine months ended September 30, 2013 primarily as a result of a $141.8 million increase in accounts payable, and a $31.0 million increase in other current liabilities, offset slightly by a $65.5 million decrease in advances from partners, a $30.2 million decrease in current deferred income taxes, $20.4 million decrease in interest payable, and a $14.7 million decrease in taxes payable. We maintain access to funds that may be needed to meet capital requirements through our Credit Facility described in "Financing Requirements" above.

Natural Gas in Underground Storage

We record our natural gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. The natural gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments, especially during periods of colder weather. In determining the lower of cost or market for storage gas, we utilize the natural gas futures market in assessing the price we expect to be able to realize for our natural gas in inventory. A decline in the future market price of natural gas could result in write-downs of our natural gas in underground storage carrying cost.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. The Board of Directors has approved our use of financial products for the reduction of interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our customers and their dispersion across geographic areas. No single customer accounted for greater than 10% of revenues for the nine months ended September 30, 2013. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At September 30, 2013, we had approximately $1.9 billion of total debt with a weighted average interest rate of 5.03%. Our revolving credit facility has a floating interest rate (2.14% at September 30, 2013). At September 30, 2013, we had borrowings outstanding of $243.4 million under our Credit Facility.

Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. At September 30, 2013, the Company had a net derivative asset position of $1.3 million related to interest-rate swaps. A 10% increase or decrease in interest rates would not result in a material increase or decrease in the aggregate fair value of outstanding interest-rate swap agreements. For a summary of the Company's open interest-rate derivative positions, see Note

7-Derivative Instruments in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production and to hedge activity in our Midstream Services segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps) and (3) the purchase and sale of index-related puts and calls (collars) that provide a “floor” price, below which the counterparty pays funds equal to the amount by which the price of the commodity is below the contracted floor, and a “ceiling” price above which we pay to the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major commercial banks, investment banks and integrated energy companies which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, given the recent volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At September 30, 2013, the net fair value of our financial instruments related to natural gas production was a $192.3 million asset.

	Volume (Bcf)	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at September 30, 2013 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2013	84.4	$ 4.68	$ –	$ –	$ –	$ 91.5
2014	232.7	$ 4.41	$ –	$ –	$ –	$ 126.1
Basis Swaps:						
2013	6.5	$ –	$ –	$ –	$ 0.09	$ 0.9
2014	16.7	$ –	$ –	$ –	$ 0.05	$ 4.7
2015	0.9	$ –	$ –	$ –	$ 0.17	$ 0.1
Fixed Price Call Options:						
2015	199.8	$ –	$ 5.09	$ –	$ –	$ (31.0)

At September 30, 2013, our basis swaps did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gain (loss) on derivatives. For the nine months ended September 30, 2013, we recorded a mark to market loss on derivatives of $26.9 million related to fixed price call options that did not qualify for hedge accounting treatment, a mark to market gain on derivatives of $96.6 million related to fixed price swaps not designated for hedge accounting, and a mark to market gain on derivatives of $1.6 million related to the basis swaps that did not qualify for hedge accounting treatment and a loss of $2.2 million related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC’s rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2013 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

In August 2013, the Company implemented an accounting module in its Enterprise Resource Planning (ERP) system. Implementing an accounting module in an ERP system involves significant changes in business processes that management believes will provide several benefits including more standardized and efficient processes throughout the Company. This implementation has resulted in material changes to the Company’s internal controls over financial reporting, as that term is defined Rules 13(a)-15(f) and 15(d)-15(f) under the Exchange Act, for the three months ended

September 30, 2013. Therefore, the Company has modified the design, operation and documentation of certain internal control processes and procedures to address the new environment associated with implementation. The system changes were undertaken to integrate systems and consolidate information, and were not undertaken in response to any perceived or actual deficiency in the Company's internal controls over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

The Company is subject to laws and regulations relating to the protection of the environment. Our policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position, results of operations, and cash flows.

Tovah Energy

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273rd District Court in Shelby County, Texas (collectively, the "Sixth Petition"), plaintiff alleged that, in 2005, they provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiff's allegations in the Sixth Petition included various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 2005 and February 2006. In the Sixth Petition, plaintiff sought actual damages of over $55.0 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of $46.0 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. In December 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. In February 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. In March 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred in April 2011 and was unsuccessful. In June 2011, SEPCO received by mail a letter dated June 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. In July 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response in July 2011. In July 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 2011 consistent with his findings in his June 2011 letter and the disgorgement award. In August 2011, a judgment was entered pursuant to which plaintiff and intervenor are entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees which currently are estimated to be up to $8.9 million and all costs of court of the plaintiff and intervenor. In September 2011, SEPCO filed a motion for a new trial and in November 2011 filed a notice of appeal.

In November 2011, the court approved SEPCO's supersedeas bond in the amount of $14.1 million, which stays execution on the judgment pending appeal. The bond covers the $11.4 million judgment for actual damages, plus $1.3 million in pre-judgment interest, $1.3 million in post-judgment interest (estimating two years for the duration of appeal), and court costs.

In June 2012, SEPCO filed its appellate brief and, in June 2012, plaintiff and intervenor filed a cross-appellate brief seeking limited remand to reassess the disgorgement determination. The parties filed their responses to the appellate and cross appellate briefs in November 2012. Oral argument was held before the Tyler Court of Appeals on March 8, 2013. On July 10, 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding plaintiff and intervenor $23.9 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11.4 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that plaintiff and intervenor take nothing under those theories of recovery, (3) the award of $11.4 million to plaintiff and intervenor as damages for misappropriation of trade secret is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for SEPCO as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. On July 25, 2013, SEPCO filed its motion for rehearing with the Tyler Court of Appeals, seeking reversal of every part of plaintiff and intervenor's recovery, and plaintiff and intervenor filed a court-ordered response. Plaintiff and intervenor filed their own motion for rehearing, and to date SEPCO has not been ordered to respond.

Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $45.5 million, including interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

Bureau of Land Management

In March 2010, the Company's subsidiary, SEECO, was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefore and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. In September 2013, the U.S. Attorney's Office requested additional information regarding this matter. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

ITEM 1A. RISK FACTORS.

There were no additions or material changes to the Company's risk factors as disclosed in Item 1A of Part I in the Company's 2012 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

Our sand mining operations, in support of our E&P business, are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.106) is included in Exhibit 95.1 to this Form 10-Q.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(31.1)Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31.2)Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(32.1)Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(95.1)Mine Safety Disclosure.

(101.INS)Interactive Data File Instance Document.

(101.SCH)Interactive Data File Schema Document.

(101.CAL)Interactive Data File Calculation Linkbase Document.

(101.LAB)Interactive Data File Label Linkbase Document.

(101.PRE)Interactive Data File Presentation Linkbase Document.

(101.DEF)Interactive Data File Definition Linkbase Document.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated:	October 31, 2013	/s/ R. CRAIG OWEN
		R. Craig Owen Senior Vice President and Chief Financial Officer